



STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL
PO Box 43172 • Olympia, Washington 98504-3172

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MAR 16 2004

OFFICE OF AIR QUALITY

March 15, 2004

To: Federal Land Managers involved in PSD review for facilities in Washington State

Subject: Satsop Combustion Turbine Project - Application for PSD Permit Extension

Dear Federal Land Managers:

On January 19, 2004, Duke Energy Grays Harbor (Duke) and Energy Northwest submitted a request for extension of the Satsop Combustion Turbine Project (Satsop CT) Prevention of Significant Deterioration (PSD) Permit No. EFSEC/2001-01, Amendment 1. The Energy Facility Site Evaluation Council (EFSEC) is the permitting agency for this facility under Chapter 80.50 Revised Code of Washington, and Title 463 of the Washington Administrative Code (WAC).

EFSEC is beginning the review of this request for permit extension as required by Chapter 463-39 WAC. EFSEC contracts with the Washington Department of Ecology, Air Quality Program, to review such permit actions and prepare draft PSD approvals. The lead Ecology permit writer for the review of this request is Alan Newman.

In order to satisfy PSD permitting requirements, EFSEC must transmit PSD applications to Federal Land Managers for their review. Enclosed is a copy of the January 19, 2004 Duke/Energy Northwest request, and an additional submittal dated February 26, 2004.

Please submit any comments you may have on this application for PSD permit extension by April 23, 2004, directly to Mr. Alan Newman, Department of Ecology, Air Quality Program, P.O. Box 47600, Olympia, WA, 98504-7600. Questions of a technical nature should also be directed to Alan Newman at (360) 407-6810.

If you have any questions about EFSEC's review of this request for extension, or the Satsop CT facility in general, please call me at (360) 956-2047.



Federal Land Managers

March 12, 2004

Page 2 of 2

2004 MAR 18 AM
Sincerely,


Irina Makarow
Siting Manager

cc: Darwin Morse, National Park Service
Elizabeth Waddell, National Park Service
Bob Bachman, United States Forest Service
Dan Meyer, U.S. EPA, Region X
Richard Stedman, OAPCA
Alan Newman, Ecology
Mike Mills, EFSEC



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JAN 21 2004

ENERGY FACILITY SITE
EVALUATION COUNCIL

GOCT-04-002
January 19, 2004

Mr. Allen Fiksdal, EFSEC Manager
Energy Facility Site Evaluation Council
Post Office Box 43172
Olympia, Washington 98504-3172

Subject: **REQUEST FOR EXTENSION AND MODIFICATION OF THE NOTICE OF CONSTRUCTION/PREVENTION OF SIGNIFICANT DETERIORATION (NOC/PSD) PERMIT TO CONSTRUCT SATSOP COMBUSTION TURBINE PROJECT NO. EFSEC/2001-01 AMENDMENT 1**

Dear Mr. Fiksdal:

On behalf of Duke Energy Grays Harbor, LLC and Energy Northwest (hereafter referred to as Duke Energy), Mr. Craig Bressan and Ms. Laura Schinnell recently met with Mr. Alan Newman of the Department of Ecology to discuss issues regarding the NOC/PSD permit for the Satsop Combustion Turbine Project. We appreciate Alan's willingness to meet with us and discuss these issues, and we look forward to an opportunity to meet with you to discuss them as well.

We are writing now to request an extension of the above-referenced NOC/PSD permit. Duke Energy remains committed to the completion of the Satsop project, but the current permit will expire before we expect to complete construction. At Alan Newman's suggestion, we are enclosing an updated Best Available Control Technology (BACT) analysis to support our request for the extension.

In addition to an extension, Duke Energy is requesting some clarifications and revisions to the NOC/PSD permit, which we have discussed with Alan Newman. The clarifications and revisions are summarized below.

REQUEST FOR EXTENSION AND MODIFICATION

January 19, 2004

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1. Clarify the Definition of Startup/Shutdown

Duke Energy requests that the permit's definition of "start-up" and "shutdown" be clarified as follows:

"Start-up" shall be defined as the period between when the combined cycle systems are initially started until the combustion turbine achieves combustion operational Mode 6.

"Shutdown" shall be defined as the period beginning when the combustion turbine leaves operational Mode 6 and ending when combustion has ceased.

"Mode 6" is defined by the manufacturer as the low emissions mode during which all 6 of the burner nozzles are in use, burning a lean premixed gas for steady-state operation.

We have discussed this issue with Alan Newman, and we believe that this language would more clearly describe the startup and shutdown process. It would also facilitate compliance monitoring because the continuous emission monitoring system will indicate and record the combustion turbine operational mode, including when the emissions unit is shutdown and when operating in start-up and shutdown modes. This system will also be used to demonstrate compliance with the NO_x and CO emission limitations during steady-state operation (Mode 6). We believe this change in definition is consistent with other NOC/PSD permits.

2. Clarify the Averaging Period for Catalyst Replacement

The permit currently requires catalyst replacement when ammonia concentrations reach 4.5 ppm. Duke Energy requests that this provision be clarified to indicate that the concentration be calculated, for purposes of this provision, using a calendar month average, excluding startup/shutdown conditions. In addition, the permit should specify that a valid monthly average will require a minimum of 200 valid hours of normal operation. This request is consistent with our recent discussions with Alan Newman.

3. Modify Stack Testing Requirements

Duke Energy requests several revisions in the permit's stack testing requirements, which we have discussed with Alan Newman. We believe that the requested changes would provide sufficient basis for EFSEC to confirm compliance with the permit's emission limits, while reducing the time and resource burden on the permit holder. We also believe these changes are consistent with other NOC/PSD permits.

Sulfur testing – Duke Energy proposes the use of Sulfur and Gas Calorific Value (GCV) data from a Gas Chromatograph (GC). The data collected by the GC will be used to calculate the actual Sulfur Oxide emissions from the turbines

Mr. Allen Fiksdal

REQUEST FOR EXTENSION AND MODIFICATION

January 19, 2004

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Sulfuric acid, VOC and PM testing – Duke Energy proposes a phased testing schedule, based on the results of the initial compliance testing.

4. **Change the Averaging Period & Clarify the Basis of NOx Limits**

Duke Energy requests that the averaging period for the short-term 2.5 ppm NOx limit be changed from 1-hour to a 3-hour rolling average (based on block hours). We are not requesting any change to the permit's current 2.0 ppm 24-hour limit.

We would also like the permit to clarify that Duke Energy has agreed to the 2.5 ppm (3-hour) / 2 ppm (24-hour) limits in the permit in light of concerns about regional haze issues. Although Duke Energy has agreed to these limits, they are more stringent than BACT would require. According to the enclosed BACT analysis, these limits have not been demonstrated to be cost effective control from proven technology. The enclosed BACT analysis indicates that BACT requires 3 ppm NOx control. Although Duke Energy is willing to go beyond BACT at this facility, we request that the permit clarify the basis for the NOx limits.

5. **Revise CO Limit in Light of New Information**

The current PSD permit limits CO emissions to 2.0 ppm. After reviewing recent operating data from similar facilities, we have determined that the current emissions limit was based on an inaccurate BACT analysis. We have revised the analysis based on recent operating data and concluded that BACT only requires a 6 ppm CO emission limit. However, in light of concerns about CO emissions expressed by Alan Newman, Duke Energy is willing to go beyond what BACT would require and commit to a 4.0 ppm CO permit limit for this facility.

By way of background, the economic analysis accompanying the current permit was based on an assumption that the turbines would emit CO at a rate of 22.6 ppm without any post-combustion control technology. Catalytic oxidation technology could be used to reduce the emission rate to 2 ppm. The cost associated with this assumed 20.6 ppm reduction in the emission rate was calculated to be only \$1,792 per ton of CO reduced.

We have obtained recent data indicating that CO emissions from the turbines are actually much lower without any post-combustion control technology. Recent data from identical GE 7FA turbines shows that CO emissions are consistently below 6.0 ppm during normal operations. As a result, the cost per ton of implementing catalytic oxidation is much higher. The enclosed BACT analysis calculates the cost of using catalytic oxidation to reduce emissions from 6.0 ppm to 2.0 ppm as \$15,574, which exceeds the cost-effectiveness required by BACT. The cost per ton rises to \$23,480 when the 2 ppm limit is compared to the 4 ppm limit that Duke Energy is willing to accept.

Mr. Allen Fiksdal

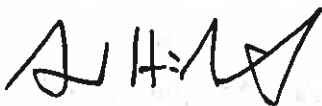
REQUEST FOR EXTENSION AND MODIFICATION

January 19, 2004

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Duke Energy would like to follow-up this letter with a meeting with you and other appropriate parties at your earliest convenience. Thank you for your time and consideration and we look forward to working with you towards a timely resolution. Please contact Mr. Craig Bressan at (704) 382-6507 or Mr. Andy McNeil at (360) 482-4345 if you have any questions or require further information with respect to this information.

Respectfully submitted,



Duke Energy Grays Harbor, LLC
By Andrew H. McNeil, Project Director



Energy Northwest
By Laura Schinnell, Project Scientist

.cc: Mr. Alan Newman, P.E. – Department of Ecology

Enclosure: Revised Best Available Control Technology Determination

REVISED BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION

Satsop Combustion Turbine Project # EFSEC/2001-01 Amendment 1

Elma, Washington

January 2004

1 DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

1.1 DEFINITION

According to state and federal clean air laws, all new sources of air pollution are required to utilize Best Available Control Technology (BACT). BACT is defined as an emission limitation based on the most stringent level of emission control available or applied at an identical or similar source (40 CFR 52.21(b)(12)) and WAC 173-400-030(12). Satsop must achieve this level of control or prove it is technically or economically infeasible before a less stringent level of control is allowed.

1.2 BACT FOR GAS TURBINE/HEAT RECOVERY STEAM GENERATOR SYSTEMS

1.2.1 NITROGEN OXIDES CONTROL

NO_x is generated during the combustion of fuels from the nitrogen in the air reacting with oxygen or from the reaction of nitrogen compounds in the fuel with oxygen. The use of natural gas minimizes the total quantity of NO_x that is generated compared to other fuels because natural gas contains essentially zero fuel bound nitrogen. The emissions of NO_x can be controlled through the use of combustion modifications or add-on emission control technologies.

The following control technologies were considered for NO_x reduction from the combustion turbine/duct burner units:

1.2.1.1 Steam or Water Injection:

Steam or Water injection are similar technologies that have been widely used as a gas turbine NO_x emission control. Steam or water is injected into the combustion zone to lower the peak combustion zone flame temperature. High-purity water must be used to prevent turbine corrosion, deposition of solids on the turbine blades, or particulate erosion of the turbine blades.

Typical steam/water injection rates range from 0.5 to 2.0 pounds of steam and 0.3 to 1.0 pounds of water per pound of fuel. The NO_x reduction efficiency of the steam/water injection depends on turbine design. Typical emission rates of 25 – 42 ppm @ 15% O₂ are capable of being produced through the use of steam/water injection. For a given turbine design, the maximum water/fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine. Different turbine designs have different maximum water/fuel ratios.

This technology alone will not satisfy regulatory requirements without the addition of a post-combustion control. This technology is not proposed for implementation on the Satsop CT Project.

1.2.1.2 Dry Low NO_x Combustor:

The modern, dry low NO_x combustor technology is typically a three-stage, lean, premix design, which utilizes a central diffusion flame for overall flame stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower peak combustion flame temperature resulting

in lower thermal NO_x formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperature, throughout the combustor-loading regime. The dry low-NO_x combustor reduces NO_x emissions by up to 87 percent over a conventional combustor. Typical emission rates of 9 – 25 ppm @ 15% O₂ can be achieved through this design.

An advanced, Dry Low NO_x combustor will be an integral part of the combustion turbines permitted for the project. This technology is guaranteed by the manufacturer to reduce NO_x emissions from the combustion turbines to 9 ppm for natural gas firing. While this technology has the lowest overall costs and environmental impact, it does not satisfy current regulatory requirements without the addition of a post-combustion control.

1.2.1.3 XONON:

This experimental technology provides combustion modifications by lowering the peak combustion temperature to reduce formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies cannot provide. The overall combustion process in the XONON system is a partial combustion of the fuel in a catalyst module, followed by completion of the combustion downstream of the catalyst. The manufacturer indicates that the technology is capable of producing NO_x emissions of 2 ppm or lower.

XONON is an innovative technology that is currently commercially available only for certain small combustion turbines, typically with electrical outputs below 10 MW in simple-cycle mode. This technology has not been proven and is not commercially available for turbines within an equivalent size range as that proposed for the Satsop CT Project. Therefore, this technology is deemed technically infeasible for use on this size class of combustion turbine.

1.2.1.4 SCONOX:

This technology is a post-combustion control system that uses a carbonate coated catalyst installed to remove both NO_x and CO without use of a reagent such as ammonia. The NO_x emissions are oxidized to NO₂ and then adsorbed onto the catalyst. CO is oxidized to CO₂. VOCs are partially reduced as well. A dilute stream of hydrogen gas is passed through the catalyst periodically to desorb the NO₂ from the catalyst and reduce it to N₂ prior to exit from the stack. This control technology is utilized on a small combustion turbine, approximately 28 MW, in Vernon, California in December 1996.

Only one equivalent sized turbine project in California has a permit which includes SCONOX as the NO_x control for a GE 7F scale combustion turbine. One of the 4 turbines at this facility is permitted to use either SCONOX or SCR, but, regardless of the technology used, must meet the same Lowest Achievable Emission Rate based emission limitation because the facility is located in an ozone nonattainment area. In fact, that facility has utilized SCR on all four turbines. Therefore, SCONOX is considered unproven for large power plants such as the Satsop CT Project.

The following cost data is based on original design and installation. The costs of retrofitting a partially constructed facility would be significantly more. Cost data submitted to Duke Energy by SCONOX's vendor indicates that annualized cost would be \$4,757,834 per turbine resulting in an

incremental cost effectiveness of \$12,521 per ton of NO_x removed. The cost for SCONOX is unreasonably high and above the range considered cost effective for comparable projects.

1.2.1.5 Selective Catalytic Reduction:

Selective catalytic reduction (SCR) is a post-combustion NO_x control technology where ammonia (NH₃) is injected into the flue gas, upstream of a vanadium oxide based catalytic reactor. The catalyst bed operates at a temperature between 600 and 800°F, temperatures typically found within the HRSG unit. On the catalyst surface, the NH₃ reacts with NO_x to form molecular nitrogen and water. Typical SCR Systems are designed to achieve NO_x emission rates of 2 – 5 ppm.

The process uses approximately 1 – 1.3 moles of NH₃ per mole of NO_x reduced and to assure that there is adequate NH₃ for the NO_x reduction reaction to take place. An allowable ammonia 'slip' of 5 to 10 ppm is commonly applied when permitting of SCR on combustion turbines. In actual operation, slip levels below 5 ppm routinely occur. However, the equipment manufacturers have not always been willing to guarantee meeting the NO_x emission rates with NH₃ limits below 10 ppm.

The primary variable affecting NO_x reduction is temperature. If operating below the optimum temperature range, the catalyst activity is reduced, allowing unreacted NH₃ to slip through into the exhaust stream. If operating above the optimum temperature range, NH₃ is oxidized, forming additional NO_x, and the catalyst may suffer thermal stress damage. SCR cannot be used effectively on waste gas streams that contain large amounts of particulate matter or sulfur dioxide. Particulate and sulfur oxide compounds deposit on the catalyst surface degrading the catalyst and prevent NO_x reduction reaction from occurring.

Duke has proposed to use GE dry low NO_x combustors on the turbine, low NO_x burners for the duct burners, and SCR to control NO_x. The annualized cost for using SCR is \$1,218,404 per turbine or \$3,354 per ton of NO_x reduction under full plant operation. This cost estimate is based on a 3.0 ppm NO_x target. The cost analysis for a 2.0 ppm NO_x target is highly dependent on catalyst life. The projections on catalyst life at these levels are not based on actual operations data. These costs are within the range of costs normally expected for the emission controls representing NO_x BACT for natural gas fired combustion turbines. The Dry low NO_x combustors, low NO_x burners for the duct burners, plus SCR are considered to be BACT for this project.

The Grays Harbor project will exceed BACT and target NO_x emissions from each CGT of 2.0 ppm (24 hour average) and 7.89 kg/hr (17.4 lb/hr). The lower emissions limits address regional haze issues.

1.2.1.6 The following table lists the emission controls considered for BACT and provides a quick synopsis of the above material.

TABLE 2
NO_x EMISSION CONTROL FOR AVAILABLE CONTROL TECHNOLOGIES FOR EACH CGT AT
THE SATSOP COMBUSTION TURBINE PROJECT

Emission Control Mechanism	NO _x Emission Concentration (ppmvd @ 15% O ₂ and ISO)	NO _x Emission Rate kg/hr (lb/hr)	Control Efficiency (Ratio to NO _x Control)	Cost Effectiveness (\$/ton pollutant controlled)
Conventional Combustor	72.4	285.2 (628.8)*	0%	0
Low NO _x duct burner	8.3	20.1 (44.2)*		
Total emissions	80.7	305.3 (673.0)		
Dry Low NO _x (DLN) Combustor	9**	35.4 (78.1)	87.6%	0
Low NO _x duct burner	8.3	20.1 (44.2)		
Total emissions	17.3	55.5 (122.3)		
DLN w/SCR (with duct burner firing)	3.0	12.6 (27.8)***	95.5%	\$3,354
DLN w/SCONOX (with duct burner firing)	2	7.89 (17.4)	97.2%	\$12,521

*Based on AP-42, Section 3.1, Table 3.1-1, April 2000, for turbine emissions and AP-42, Section 1.4, Table 1.4-1, September 1998, for duct burner emissions. At maximum duct burner operating rate, the duct burner contributes 8.3 ppm to the NO_x emissions.

**Emissions calculated by General Electric and Duke/Fluor-Daniel.

1.2.1.7 Emission Limits, Monitoring and Reporting requirements for NO_x:

SCR with dry low NO_x combustors and Low NO_x duct burners represent BACT for NO_x control. The NO_x from each CGT shall not exceed a 3-hour average of 2.5 ppm at 15% O₂ and ISO conditions, and 12.6 kg/hr (27.8 lb/hr). These limits represent the maximum emission rate that occurs while duct firing is occurring and the daily average operating rate of the turbines.

NO_x emissions, O₂ content and exhaust gas flow rate from each exhaust stack shall be measured and recorded by a continuous emission monitoring system that meets the requirements of 40 CFR Part 75. Emissions reporting to Environmental Protection Agency (EPA) for compliance with the Acid Rain program shall be on the frequency and in the format required by EPA. This same information will be supplied to the Energy Facility Site Evaluation Council (EFSEC) on the same reporting frequency.

1.2.2 CARBON MONOXIDE CONTROL

Carbon monoxide (CO) is an odorless, colorless, toxic gas that is formed when carbon containing compounds are burned. The rate of formation for CO is directly related to combustion efficiency, available oxygen, and combustion temperature. In the atmosphere, CO is converted to carbon dioxide over a period of a few days.

The following control options were considered for CO control:

1.2.2.1 Dry Low NO_x combustors:

The use of dry low NO_x combustors on the gas turbines and low NO_x combustors for the duct burners is the base emissions case for this project. The dry low NO_x combustors are designed to minimize the formation of NO_x while also working to minimize the formation of CO. These are usually opposing functions, but the manufacturers have been able to optimize the combustors to minimize both compounds.

The dry low NO_x combustors on the combustion turbines have a CO emission rate of 9 ppm. Actual operating data has demonstrated CO emissions rates less than 6 ppm. The low NO_x combustors for the duct burners produce 13.6 ppm of CO, actual CO emissions rates have been demonstrated at less than 6 ppm total. Although manufacturer specifications estimate CO emissions at 22.6 ppm of CO with duct burners, actual emissions data from similar facilities demonstrates CO emissions < 6.0 ppm @ 15 % O₂. Duke proposes the installation of dry low NO_x combustors as BACT.

1.2.2.2 SCONOX:

CO is also controlled by the SCONOX process. SCONOX oxidizes CO and some VOCs to CO₂ and water through the use of a platinum catalyst. Through the use of SCONOX, CO emissions can be reduced by 90+%, resulting in emission concentration of 1 – 2 ppm. The SCONOX system would remove 302 tons of CO per CGT per year at a cost effectiveness of \$15,574 per ton. This cost is considerably above the normal range of cost effectiveness applied to CGTs for CO control. The installation of SCONOX at this stage of construction would be even more expensive.

SCONOX has the ability to reduce multiple pollutants. A cost effectiveness analysis using the 'excess cost' above the cost attributable to reduce NO_x can be applied to a CO reduction BACT cost effectiveness determination. Using this concept, the excess annual cost of SCONOX applicable for evaluating SCONOX for CO control results in a cost effectiveness of \$11,688/ton CO reduced. This cost is above the normal range of cost effectiveness for CO control systems applied to CGTs for CO control. Again, changing the design to install SCONOX at this stage would be even more expensive.

1.2.2.3 Catalytic Oxidation:

Catalytic oxidation controls carbon monoxide by causing the hot exhaust gas to pass through a platinum catalyst section where oxygen in the gas stream is reacted with CO to produce CO₂. Some of the VOCs in the flue gas also react to form CO₂ and water.

This technology is capable of reducing CO concentration by 90+%. Based on actual operating data from similar facilities the actual emissions from the dry low NO_x burners are less than 6.0 ppm average. The use of an oxidation catalyst would remove an estimated 40.5 tpy of CO per CGT. The cost effectiveness of this technology is estimated at \$15,655 per ton CO reduced. The cost of a CO catalyst is unreasonably high and above the range considered cost effective for comparable projects.

The following table lists the emission controls considered for CO BACT and provides a quick synopsis of the above material.

TABLE 3
 CO EMISSION CONTROL FOR AVAILABLE CONTROL TECHNOLOGIES FOR EACH CGT AT
 THE SATSOP COMBUSTION TURBINE PROJECT

Emission Control Mechanism	CO Emission Concentration (ppm @ 15% O ₂)	CO Emission Rate kg/hr (lb/hr)	Control Efficiency (Ratio to CO Control)	Cost Effectiveness (\$/ton pollutant controlled)
Dry Low NO _x (DLN) Combustor	6**	9.09 (20.0)	0%	0
Low NO _x duct burner	6**	4.77 (10.5)		
Total emissions	6**	13.86 (30.5)		
DLN w/CO catalyst (with duct burner firing)	2.0**	4.81 (10.6)**	85.3%	\$15,655
DLN w/SCONOX (with duct burner firing)	2.0**	4.81 (10.6)**	85.3%	\$11,688

*Based on the actual emissions from identical equipment typically produces less than 6.0 ppm with duct burners.

**Emissions calculated by General Electric and Duke/Fluor-Daniel.

1.2.2.4 Emission Limits and Monitoring Requirements for CO :

Catalytic oxidation in addition to combustion controls is LAER for CO control. BACT is a dry low NO_x burner, CO emissions from each CGT exhaust stack shall not exceed a 3-hour average of 6.0 ppm at 15% O₂, and 13.86 kg/hr (30.5 lb/hr) with duct firing. This represents the maximum emissions rate while duct firing.

Each turbine stack will be equipped with continuous CO monitors that meet the requirements of 40 CFR 60, Appendices B and F. The emissions will be complied and reported to EFSEC on the same schedule as the NO_x emissions.

1.2.3 VOLATILE ORGANIC COMPOUNDS (VOC)

Volatile organic compounds encompass organic compounds that participate in ozone formation reactions with NO_x. In the atmosphere, these compounds react with NO_x and other photoactive chemicals to form ozone and other nitrogen containing, reactive organic chemicals. The dominant VOCs found in the exhaust of a gas combustion turbine are aldehydes such as formaldehyde and acetaldehyde.

The following control options were considered for VOC control:

1.2.3.1 Dry Low NO_x combustors and low NO_x duct burners:

This is the "no further control" option. The VOC control technologies discussed above are based on volatile organic compound emission reductions from this level. The VOC emissions from use of these combustors is, 2.8 ppm @ 15% O₂, 1 hour average, and 2.86 kg/hr (6.3 lb/hr), both expressed as carbon equivalent. The BACT cost effectiveness is \$0. The use of dry low NO_x combustors fired on natural gas represents BACT for VOC emission control for this source.

1.2.3.2 Thermal Oxidation, Carbon Adsorption, Condensation and Absorption:

There is concern for the application of these technologies to the very dilute VOC concentrations and high temperatures in the exhaust of a combustion turbine. All of these technologies have demonstrated better efficiencies when used to control exhausts containing significantly higher concentrations of hydrocarbons. As such, these technologies are currently considered to be technically infeasible for use on combustion turbines.

1.2.3.3 SCONOX:

SCONOX reduces VOC emissions at the same time it reduces NO_x and CO. SCONOX reduces VOC emissions by catalytically oxidizing the VOCs to carbon dioxide (CO₂). SCONOX is capable of reducing VOC emissions by 90%. A 90% reduction in VOC emissions represents 33 tpy of VOCs reduced.

The cost effectiveness of SCONOX applied exclusively as a VOC control is \$144,177/ton VOC removed per CGT. This cost effectiveness is well above what has been accepted as cost effective emission controls.

SCONOX has the ability to reduce multiple pollutants. A cost effectiveness analysis using the "excess cost" above what is necessary to reduce NO_x and CO can be applied to a VOC reduction BACT cost effectiveness determination. Based on the cost effectiveness procedure noted above, the cost effectiveness of SCONOX applied as a VOC control is \$91,814/ton VOC removed per turbine. This cost effectiveness is about 30 times higher than the normal range of cost effectiveness' applied to CGTs for VOC control.

1.2.3.4 Catalytic Oxidation:

Catalytic oxidation reduces VOCs at the same time it reduces CO. An oxidation catalyst reduces VOC emissions by catalytically oxidizing VOCs to CO₂ and water. The technology is capable of reducing VOCs up to 90%.

The rate and degree of VOC oxidation occurring across the catalyst can be affected by its operating temperature, which is related to the catalysts location within the HRSG. Higher catalyst temperatures do lead to higher oxidation rates, but at the expense of steam production. VOC reduction by an oxidation catalyst is also affected by the molecular weight of the organic compound. It is generally accepted by manufacturers and regulators that because formaldehyde is a simple and partially oxidized organic compound, it will oxidize at about the same time and to the

same degree as CO¹.

An 80% reduction in VOC emissions would be 29.4 tpy per turbine. Assuming the cost of an oxidation catalyst is solely for VOC control, the BACT cost effectiveness would be \$16,987/ton VOC reduced.

1.2.3.5 The following table lists the emission controls considered for BACT and provides a quick synopsis of the above material.

TABLE 4
VOC EMISSION CONTROL FOR AVAILABLE CONTROL TECHNOLOGIES FOR EACH CGT AT
THE SATSOP COMBUSTION TURBINE PROJECT

Emission Control Mechanism	VOC Emission Concentration (ppm @ 15% O ₂ and ISO)	VOC Emission Rate kg/hr (lb/hr)	Control Efficiency (Ratio to VOC Control)	Cost Effectiveness (\$/ton pollutant controlled)
Dry Low NO _x (DLN) Combustor and Low NO _x duct burner	4.36	5.48 (12.1)	0%	\$0
DLN plus low NO _x duct burners with a separate oxidation catalyst for VOC	0.44	0.55 (1.21)	90%	\$16,987
DLN plus low NO _x duct burners with SCONOX	0.44	0.55 (1.21)	90%	\$91,814

All emissions calculated by General Electric and Duke/Fluor-Daniel, and converted to carbon equivalent.

1.2.3.6 VOC Emission Limits and Monitoring Requirements:

BACT for VOC is the use of natural gas and dry low NO_x burners. VOC emissions from each CGT exhaust stack shall not exceed a 24 hour rolling average of 2.86 kg/hr (6.3 lb/hr), expressed as carbon equivalent. This emission limit represents maximum emissions that occur during duct firing.

EPA Reference Method 25A or 25B, or an equivalent method agreed to in advance by EFSEC, shall determine initial and continuing compliance with the VOC limitation. The routine indication of compliance will be provided by compliance with the CO limitation.

¹ Roy, Sims; Emission Standards Division, Combustion Group, US Environmental Protection Agency Memorandum to Docket A-95-51; *Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines*, December 30, 1999 (<http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm>).

1.2.4 Total Pollutant Removal BACT Cost Effectiveness for NO_x, CO and VOC

Since the SCONOX process controls a number of pollutants simultaneously, we have evaluated the comparative cost effectiveness of using SCONOX and the equivalent discrete emission control components to treat the same pollutants. The following control technologies were considered in terms of total pollutant reduction:

1.2.4.1 SCONOX

As discussed in the previous paragraphs, SCONOX has the capability of reducing NO_x, CO, and VOCs simultaneously. The total expected pollutant reduction would be 785 tons per year per turbine. The annualized cost per turbine is expected to be \$4,757,834. This results in a BACT cost effectiveness of \$6,061 per ton total pollutant removal.

1.2.4.2 SCR plus Oxidation Catalyst

The use of the SCR and oxidization catalysts reduces the same pollutants as the SCONOX system and provides a control efficiency and cost effectiveness comparison. The total expected pollutant reduction from this combination of controls would be between 100 – 400 tons per year per turbine. The annualized cost per turbine is expected to be \$1,852,434. This results in a BACT cost effectiveness is estimated at \$4,631 – \$18,524 per ton total pollutant removal.

1.2.4.3 BACT Determination

In terms of total pollutant removal, BACT is determined to be SCR. Emission limitations, monitoring, and reporting requirements are listed above for the individual pollutants.

1.2.5 SULFUR DIOXIDE CONTROL

The following control options were considered for SO₂ control for this facility:

1.2.5.1 Natural Gas Fuel:

Natural gas is considered a clean fuel containing only trace amounts of sulfur. Proposed emission rates for SO₂ are based on an annual average of total sulfur content of 0.5 grains/100 scf and a maximum value of 3 grains/100 scf. The natural gas provided in most of Western Washington is unable to reliably meet the definition of pipeline natural gas given in 40 CFR 72.2². The natural gas can reliably meet the criteria for natural gas found in the same regulation.

1.2.5.2 Wet Exhaust Gas Scrubbing:

Wet scrubbing is commonly used to control SO₂ emissions from combustion sources with much higher sulfur content than natural gas fired combustion turbines. Exhaust gas is passed through a

² Most recently modified on Wednesday, June 12, 2002.

spray or packed tower scrubber using an alkaline solution of water and crushed limestone, calcium hydroxide, or sodium hydroxide. The limestone, calcium hydroxide, or sodium hydroxide reacts with the SO_2 generating calcium or sodium sulfites and sulfates. The resulting exhaust stream is passed through a mist eliminator and may require reheating to make the exhaust gas buoyant enough to leave the stack. Wet scrubbers have not been used as controls for natural gas combustion turbines because the concentration of sulfur oxides in the flue gas (in this case 0.27 ppm @ 15% O_2) is too low for known emission controls to effectively reduce SO_2 emissions. The overall technical feasibility this technology to reduce emissions of SO_2 in such a dilute exhaust gas causes this control technology to be considered technically infeasible.

1.2.5.3 Dry Exhaust Gas Scrubbing:

Like wet scrubbing, dry scrubbing uses an alkaline reagent to react with SO_2 and SO_3 in the flue gas. This control system does not use large amounts of water to introduce the reagent into the flue gas, resulting in a dry product that can be removed as a particulate from the exhaust gas. This technology has been used on concentrated sources of SO_2 such as coal-fired boilers and coke calciners. The technology has not been used to control combustion turbine emissions. Dry scrubbers have a limited temperature and minimum flue gas concentration for effective use in controlling SO_2 emissions. The concentration of SO_2 from natural gas combustion (in this case 0.27 ppm @ 15% O_2) is below the effective concentration level for dry scrubbers. The overall technical feasibility this technology to reduce emissions of SO_2 in such a dilute exhaust gas causes this control technology to be considered technically infeasible.

1.2.5.4 Natural Gas Sulfur Removal:

This is a family of chemical treatment methods that remove organic sulfur compounds and hydrogen sulfide from the natural gas. Removal of sulfur compounds from natural gas occurs near the well fields where the gas comes from. Removal of sulfur compounds from the natural gas is necessary to prevent corrosion of the steel gas transport lines and to meet various legal requirements for the quantity of sulfur compounds in natural gas. While it appears to be technically feasible for a single user to remove sulfur from the natural gas used at its own facility, the cost effectiveness of this option has not been considered before. The capital cost for a natural gas sulfur removal facility adequately sized to reduce the natural gas sulfur content of the gas used by the Satsop from approximately 0.5 grains/100 scf to 0.2 grains/100 scf has been roughly estimated at \$10,000,000 and would reduce the potential SO_2 emissions by about 35 tons per year.

1.2.5.5 BACT Determination

BACT for the Satsop CT Project is the use of natural gas as received from the Northwest pipeline.

1.2.5.6 Emission Limit, Monitoring and Reporting Requirements

The permitted maximum sulfur dioxide emissions using natural gas is calculated to be 0.27 ppm, annual average, at 15% oxygen, and a 1.6 ppm, 1 hour average at 15% O_2 , based on an annual average concentration of 0.5 grains total sulfur/100 scf and a short term seasonal concentration of 3.0 g/100 scf in the natural gas. Sulfur dioxide emissions from each CGT exhaust stack shall not exceed 1.5 kg/hr (3.3 lb/hr), annual average and 9.0 kg/hr (19.5 lb/hr), 1 hour average.

Emission monitoring for SO₂ will be achieved by the following means: 1) fuel flow monitoring and total fuel sulfur content reporting that meets the requirements in 40 CFR 72 and 75, Appendix D, and 2) installation of a gas chromatograph (GC) to monitor the total sulfur content of the gas (the GC may be owned and operated by a third party).

1.2.6 SULFUR TRIOXIDE AND SULFURIC ACID (SULFURIC ACID MIST)

Sulfur trioxide/sulfuric acid is produced in small amounts during the initial combustion of sulfur containing fuels. Additional sulfur trioxide/sulfuric acid is produced as the SO₂ in the flue gas flows across the SCR and oxidation catalysts. It is estimated that 30% of the original SO₂ leaves the PGU stack in the form of sulfur trioxide, ammonium sulfate, ammonium bisulfate, or sulfuric acid. The sulfur trioxide is quickly converted to sulfuric acid and ammonium sulfate in the ambient atmosphere.

The emission control options evaluated for SO₂ above are equally applicable to the control of SO₃ and H₂SO₄ from the turbines.

1.2.6.1 BACT Determination

The Satsop CT Project has proposed, and EFSEC agrees, that using natural gas constitutes BACT for sulfur trioxide and sulfuric acid control.

1.2.6.2 Emissions Limitation, Monitoring and Reporting Requirements

The emissions of sulfuric acid mist emissions from each CGT stack shall not exceed 0.77 kg/hr (1.7 lb/hr) or 18.51 kg/day (40.8 lb/day).

Annual testing of each CGT exhaust stack for sulfuric acid mist utilizing EPA Reference Method 8 is required for the first 3-years of operation. Sulfur trioxide converts to sulfuric acid in this emissions test method and ammonium sulfate and bisulfate salts are also collected in the method.

1.2.7 PARTICULATE AND PARTICULATE MATTER LESS THAN 10 MICROMETERS

Particulates are small particles of various materials such as metals, soil, or products of incomplete combustion. Particulates are regulated to reduce their adverse health impacts. PM is defined as fine solid or semisolid material smaller than 100 microns in size. PM₁₀ is a subset of particulate and is defined as PM smaller than 10 microns in size.

There are no demonstrated emission control measures to reduce the emissions of particulates from natural gas combustion turbines other than the use of natural gas and good combustion practices to maximize overall combustion efficiency.

1.2.7.1 BACT Determination

EFSEC agrees with Duke Energy that good combustion practices and using only natural gas is BACT for PM and PM₁₀ emissions. The proposed BACT emission limits are listed in Table 5.

1.2.7.2 Emission Limits, Monitoring and Reporting Requirements

EFSEC agrees with the Satsop CT Project that good combustion practice and using only natural gas constitute BACT for PM and PM₁₀ emissions. For permitting and modeling purposes it was assumed that PM and PM₁₀ are equal. Total PM/PM₁₀ emissions from each CGT exhaust stack shall not exceed 246.0 kg/24 hours (542.4 lb/24 hours). The proposed particulate emissions for the Satsop CT Project are shown in Table 5.

EPA Reference Method 201A and 202 shall determine initial compliance with the particulate limits. The same methods will be used for annual source testing conducted to demonstrate continued compliance.

Each CGT stack will meet a visual opacity limit of 5% for a six minute average.

TABLE 5
EMISSION LIMITATIONS FOR PARTICULATE EMISSION LIMITS FOR EACH CGT

Pollutant	Emissions kg/hr (lb/hr)	Emissions Kg/24 hours (lb/24 hours)
PM/PM ₁₀ , Turbine	7.53 (15.0) ³	--
PM/PM ₁₀ , Duct burner	2.49 (5.5)	--
PM/PM ₁₀ , sulfates and bisulfates	0.953 (2.1)	--
PM/PM ₁₀ , total	10.25 (22.6)	246.0 (542.4)

1.2.8 Turbine Start-up and Shutdown Emissions

The turbines are projected to start operations from a cold state up to 130 times per year. A cold state is when the turbine has not been operating for approximately 72-hours and the boiler water has been allowed to cool. The auxiliary boiler is used to reduce the total time it takes for the CGTs to go from cold to an operating condition. Duke Energy and GE have worked together and developed a methodology to start up the pair of turbines in each power island to reduce the start-up period to the maximum possible.

The start-up process begins with the auxiliary boiler heating the water in the HRSGs followed by one turbine being started at a minimal operational level. The purpose of this is to provide additional heat to its HRSG's boiler water. As the HRSG water increases temperature the turbine operates at higher rates and the second turbine in the power island is started. The turbine operating rate is increased until they are operating at full operational load and the HRSG is up to full operating temperature and pressure. This total process takes about 4 hours per turbine in a power island. Initially, the emission factors in Table 6 will be applied to estimate the emissions during start-up until Duke Energy develops newer factors.

³ Based on guarantee from General Electric.

TABLE 6
 START-UP EMISSIONS FACTORS

Pollutant	Emission Factor (per pair of turbines in one power island)
Nitrogen oxides	1536 lb/4-hr (average)
Carbon monoxide	5288 lb/4-hr (average)
Volatile organic compounds	354 lb/4-hr (average)

During shut-down of the equipment, emissions stop when fuel stops being burned. The emissions then end abruptly.

1.3 COOLING TOWERS:

Wet cooling towers utilize air passage through the cooling water to cool the water for reuse. This direct contact between the cooling water and the air passing through the tower results in entrainment of some of the liquid water in the air stream. The entrained water is carried out of the tower as "drift" droplets. The drift droplets generally contain the same chemical impurities and additives as the water circulating through the tower. Duke proposes to install drift eliminators capable of reducing the drift to $\leq 0.02\%$ or the recirculating water flow rate. This drift loss rate is commonly found in current generation forced draft cooling towers such as that installed for this project.

Duke/Fluor-Daniel has provided total solids information on the recirculating cooling water. The reported concentration of total solids in the recirculating water is 857 ppm (by weight). The total solids used for recent dispersion modeling was 937.5 ppm. 300 ppm of total solids is added in the form of water treatment chemicals to control the relatively high silica content of the water used for cooling, there will be sulfuric acid added to the recirculating cooling water to reduce the amount of silica that comes out of solution in the cooling tower. Other chemicals are added to reduce the growth of biofilms in the cooling tower. These total dissolved solids and additives can be converted to airborne emissions. The following formula can be used to calculate the quantity of particulate emitted from the cooling tower.

$$\frac{Q \times C \times 0.00001 \times 60 \times 8.34}{1000000} = D$$

Where: Q = recirculating water flow rate in gallons per minute = 165028 gallons per minute²
 C = total dissolved solids concentration in parts per million by weight (ppmw) = 1237.5 ppmw
 D = particulate emission rate in lb/hr.
 0.00001 = the drift loss rate in gallon lost/gallon of recirculating cooling water

Using of this equation results in an emission rate of 0.463 kg/hr (1.02 lb/hr) or 4061 kg/yr (4.5 ton/yr) of PM/PM₁₀ per cooling tower.

⁴ Derived from the application materials submitted in April, 2002 and additional information submitted on May 21, 2002.

Installation and operation of drift eliminators with a drift loss rate of 0.001% of the recirculating flow rate constitutes BACT for the cooling towers.

Initial compliance will be based on submission of a copy of the drift eliminator manufacturer's certification that the drift eliminators are installed in accordance with its installation criteria. Duke Energy is required to submit to EFSEC a methodology they will use to estimate PM/PM₁₀ emissions from the cooling towers that takes into account each cooling tower's cooling water recirculation rate, the cooling tower dissolved solids (TDS), the effects of fan operation in each cooling cell and the manufacturer's information on drift losses. The methodology shall be accepted by EFSEC prior to the first operation of a cooling tower.

Routine compliance will use the calculation methodology once each quarter to estimate the PM/PM₁₀ emissions from each cooling tower. The estimation shall include testing of the recirculating cooling water flow rate, TDS, conductivity, and silica content at the time the TDS sample is taken. An estimation of the cooling tower PM/PM₁₀ emissions shall be made and submitted as part of the initial compliance testing for each CGT and with each quarterly emissions report. The PM/PM₁₀ calculation methodology developed by Duke will be used to calculate the emission estimate.

1.4 AUXILIARY BOILER:

Duke Energy has proposed in the Satsop application that BACT for all pollutants emitted by the auxiliary boilers to be a combination of flue gas recirculation, low NO_x burners, good combustion practices, and the use of natural gas. Flue gas recirculation and low NO_x burners are commonly determined to be BACT for this size boiler when operating on natural gas fuel.

As part of its BACT determination and in recognition of anticipated actual operations, Duke Energy has proposed to limit the hours of operation of each auxiliary boiler to 2500 hours per year. This will be reflected in the approval.

1.4.1 BACT Determination and Proposed Limits

The emission controls and annual hours of operation limitation proposed by Duke Energy is accepted as BACT for all pollutants emitted by the auxiliary boilers. Table 7 gives the emission limitations for these units.

TABLE 7
 PROPOSED BACT EMISSION LIMITS FOR EACH AUXILIARY BOILER

Pollutant	Emissions (ppm) at 15% O ₂	Emissions Kg/hr (lb/hr)	Emissions Kg/yr (ton/yr)*
NO _x	30	0.467 (1.03)	1170 (1.29)
CO	50	0.485 (1.07)	1215 (1.34)
SO ₂	1	0.032 (0.07)	79.5 (0.0875)
PM/PM ₁₀	0.005 grains/dscf	3.175 (7.0)	7955 (8.75)
VOC	40	0.213 (0.469)	533 (0.586)
Opacity	6 minute average of 5%	-	-

*Based on 100% load and 2500 hours per year.

1.4.2 Routine Monitoring and Reporting Requirements

Routine compliance will be indicated through boiler operating records indicating hours of operation and fuel flow, and the application of an emission factor derived from stack testing of the installed boilers and periodic stack tests taken at 5 year intervals after the initial compliance test.

Monitoring information will be reported to EFSEC on a quarterly basis at the same time as the reporting for the CGTs.

1.5 DIESEL FUELED EMERGENCY GENERATORS AND EMERGENCY FIRE PUMPS.

These are diesel fueled reciprocating engines. The emergency generators are rated at 500 kilowatts (671 horsepower) and are proposed to be permitted at no more than 500 hours per year. These engines are required to meet the emission requirements for new Tier 2, non-road compression ignition engines of this size class found in 40 CFR 89, Subpart B.

1.5.1 Emission limits for diesel emergency generators

TABLE 8
 EMISSION LIMITATIONS FOR DIESEL EMERGENCY GENERATORS

Pollutant	Emissions g/kw-hr	Emissions kg/hr (lb/hr)	Emissions kg/yr (ton/yr)
NO _x plus VOC	6.4	2.38 (5.26)	1196 (1.3)
CO	3.5	1.75 (3.86)	875 (0.965)
PM/PM ₁₀	0.20	0.10 (0.22)	50 (0.055)
SO ₂	--	0.122 (0.269)	60.78 (0.067)
Opacity	6 minute average of 5%	-	-

1.5.2 Emissions for emergency fire water pumps

The emergency fire water pumps are intended to operate only when electrical power is not available to the site to supply water for fire suppression. As such they are intended to operate for 500 hours

per year or less. These engines will meet the new, non-road compression ignition engine requirements in 40 CFR 89, Subpart B, applicable to the emergency fire water engine size and for purchase in 2002.

1.5.3 Monitoring and Reporting Requirements for Diesel Engines

Monitoring to indicate compliance with the limits shall be by fuel purchase records indicating fuel quality and sulfur content, annual operating hours, and records indicating the nature and type of maintenance performed. Initial compliance will be by certification by the engine manufacturer that the engines meet the applicable emission criteria in 40 CFR 89.